A21. No, not exactly. The results above are based on a model run that included reasonable limits to annual builds but could be improved based on real-world constraints.[36] Further, the figures above do not reflect builds that are already under contract as part of existing programs (e.g. Duke's "Designated" category) or planned under existing programs (e.g. Duke's "Mandated" category). Figure 2 below compares the cumulative solar installation under Duke's Base Case with Carbon Policy (Designated, Mandated, and Undesignated) and the Synapse Reasonable Assumptions modeling.[37]

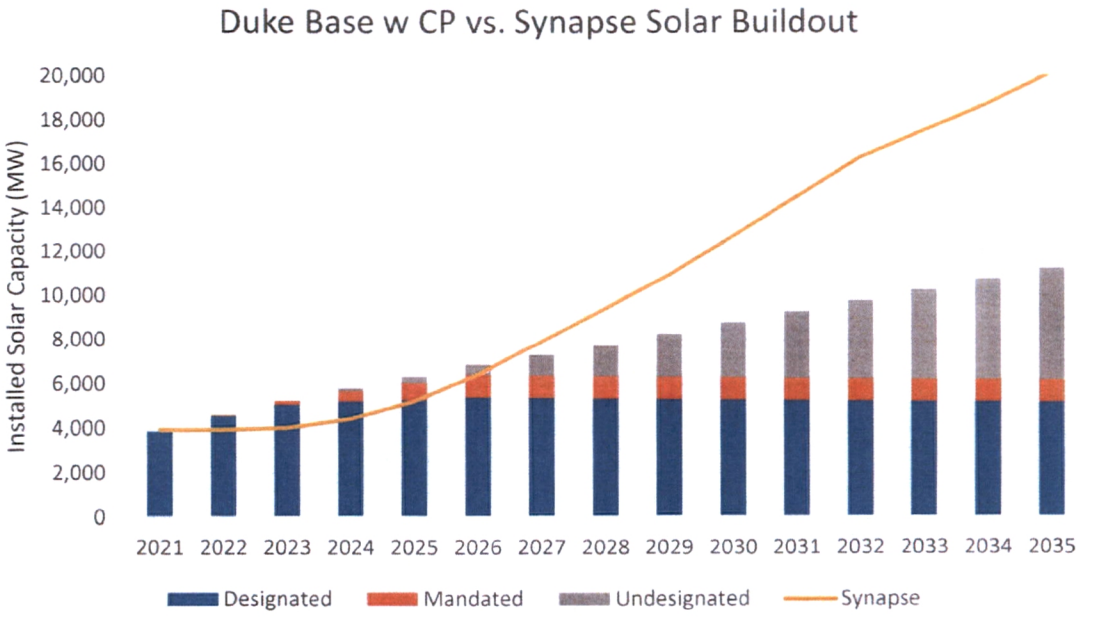

Figure 2 - Solar Buildout Comparison

Specifically, I would recommend that if Duke were to follow a path towards this 2035 resource mix target, it begin adding solar and storage earlier. This approach would allow Duke's customers to benefit from the ITC extension for both standalone solar and

[36] The model was limited to 1,500 MW of PV between 2021 and 2029 and 1,800 MW of PV in 2030 and beyond, and to 100 MW, 200 MW, and 300 MW at various years for onshore wind. Battery storage was limited to 1,660 in 2021, increased to 1,900 MW in 2027, and to 1,960 MW in 2030 and beyond.
[37] Duke figures based on Kalemba Rebuttal Exhibit 1.

solar plus storage systems while also alleviating interconnection challenges associated with the rapid modeled increase beginning in 2027. Further, by installing storage sooner, the Company will gain operational experience in that technology that it notes it is currently lacking.[38] This experience will be valuable as it begins to ramp up storage installations in the latter part of this decade. Figure 3 below proposes a more moderated build-out strategy that ensures that the minimum cumulative capacity in any year is at least as high as the Synapse modeling while moderating annual increases in capacity.[39]

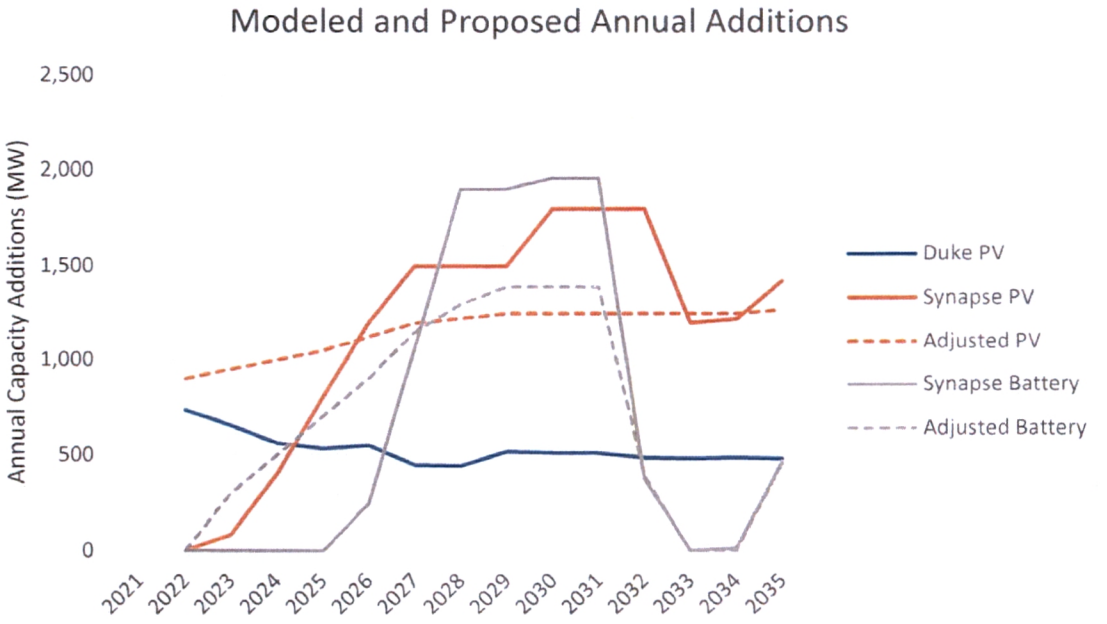

Figure 3 - Modeled and Proposed Annual Additions

Q22. HOW DOES THIS BUILDOUT COMPARE TO DUKE'S FIGURES?

[38] Exhibit KL-8, Duke Response to SCSBA's Second Request for Production to DEC/DEP ("SCSBA RFP 2") (producing Duke response to DR NCSEA 5-2) (confidential).

[39] Under the "adjusted" schedules, the total amount of solar and storage are at least as much as what was called for in that year under the Synapse modeling. This ensures that the reliability constraints that Synapse demonstrated based on given levels of solar and battery storage capacity and energy contributions will also be met under the "adjusted" schedule. See Exhibit KLS-3 for details on the annual build in both schedules.

A22. The renewable capacity buildout figures in the Synapse model are higher than those in Duke's Base case, which is not surprising give the interconnection limits that Duke imposed in its modeling. Duke's witness Mr. Kalemba testifies that its annual interconnection limits (500 MW and 900 MW for the combined DEC and DEP territories in the base and high renewable scenarios, respectively) are reasonable because "significant portions of the DEC and DEP systems are identified as 'constrained' meaning that significant transmission upgrades are required in order to add additional generation."[40] But while these constraints on the transmission system may increase the cost of required upgrades and the amount of lead time it takes to construct individual projects, they do not substantially reduce the rate at which new projects can be studied.

The sizable cost savings that are obtainable through advancing the renewable and storage buildout strongly suggest that the construction of new transmission upgrades to enable additional buildout would be fully justified. Moreover, as Mr. Kalemba acknowledges, the Commission has only recently approved Duke's interconnection "queue reform" proposal, the primary purpose of which is to make Duke's interconnection process more efficient.[41] Furthermore, Duke's capacity to study generator interconnections (on a MW basis) should increase substantially in the coming years, not only because of queue reform, but also because the projects in the interconnection queue consist increasingly of fewer large-scale transmission-interconnection projects rather than many small-scale distribution-interconnected projects. For a variety of economic and policy reasons, it is clear that the future of Duke's system will involve a dramatic ramp up of new renewable and battery storage projects, and it must be able to meet this challenge in a timely manner.

[40] Kalemba Rebuttal at 35-36.
[41] Kalemba Rebuttal at 37.

Q23. IF THE COMMISSION WERE NOT TO ORDER UPDATED MODELING IN THIS CASE, WOULD YOU STILL RECOMMEND THAT IT ORDER DUKE TO PROCEED AS RAPIDLY AS POSSIBLE TOWARDS A SIMILAR BUILDOUT AS YOU DESCRIBE ABOVE?

A23. Yes. The Synapse model shows that incorporating more renewable energy and battery storage can meet the reliability needs of Duke's system while delivering substantial savings over the planning period. It is also clear that state and federal policy, Duke's corporate goals, and commercial and individual interests are rapidly aligning towards more aggressive decarbonization. These factors, combined with modeling that supports the viability of this transition, should be sufficient for the Commission to select the direction to go and begin moving rapidly down that path. Issuing an immediate and sizable procurement for renewable energy and batteries is sufficiently justified by the record, even if the Commission does not require additional modeling to be performed.

IV. DUKE'S REBUTTAL TESTIMONY FAILS TO REMEDY THE MAJOR FLAWS IN ITS NATURAL GAS FORECAST, WHICH IS CRITICAL TO THE IRP.

Q24. PLEASE PROVIDE AN OVERVIEW OF DUKE'S REBUTTAL TESTIMONY ON ITS NATURAL GAS FORECAST METHODOLOGY.

A24. Duke witness Snider provides rebuttal testimony on its natural gas forecast methodology. Mr. Snider begins by summarizing ORS's expert witness reports on this topic.[42] He then turns to a history of avoided cost proceedings in North Carolina to provide "background and context for the Companies' natural gas forecasting methodology."[43] Finally, Mr. Snider address my direct testimony.[44]

[42] Snider Rebuttal at 62.
[43] Snider Rebuttal at 66.
[44] Snider Rebuttal at 68.

A. ORS is Critical of Duke's Natural Gas Forecast Methodology

Q25. WHAT DID ORS AND ITS EXPERTS FIND REGARDING DUKE'S NATURAL GAS FORECAST METHODOLOGY AND ASSUMPTIONS?

A25. ORS and its experts identified numerous issues with the Company's forecast methodology. For instance, ORS found that:

- Duke's prices forecasts "are consistently lower than the consensus forecasts" in the near-term.[45]
- "There are a few noticeable issues regarding the Company's forecast including the fact that it is rather flat for about ten years."[46]
- "The Company appears confident that based on actual market quotes it can lock in its gas supply for its entire system for the next ten years, which in our experience would be unusual for an electric utility to do."[47]
- "We point these concerns out because low gas price forecasts could result in indicating that natural gas-fired resources are comparatively less expensive than they otherwise would be relative to other resource alternatives."[48]
- "The Company discusses that 5 and 10-year observable market curves are at $2.39 and $2.53, which is consistent with the Company's base forecast, however, as discussed above, it is not clear that the Company would or even could in fact lock in its entire gas supply for the next ten years."[49]

[45] ORS Sandonato Direct at 49.
[46] ORS Sandonato Direct at 50.
[47] ORS Sandonato Direct at 50.
[48] ORS Sandonato Direct at 50.
[49] ORS Sandonato Direct at 51.

- "In Appendix F, the Company also discusses its need for 'additional upstream firm interstate transportation service to support existing and future natural gas generation.' With the cancellation of the Atlantic Coast Pipeline ("ACP") in July 2020, the Company has no active projects to expand its interstate gas supply."[50]
- "Without the ACP, the Company notes it will not have any direct access to Marcellus and Utica shale basins of West Virginia, Pennsylvania, and Ohio natural gas supply."[51]

Put together, ORS found significant flaws in Duke's natural gas forecast and assumptions. It correctly concluded that Duke's near-term forecast is lower than most other sources, appropriately questioned whether Duke could actually contract for its supply for ten years at those prices, and pointed out the massive risks associated with a buildout that would require new interstate pipeline capacity to be built and reserved. While I disagree with the notion that these flaws do not render the forecast results "unreasonable," ORS's critique nonetheless supports my testimony and recommendation that the Commission order Duke to revise its gas projections.

B. Duke has Repeatedly Ignored the Directive of the NCUC

Q26. PLEASE PROVIDE A SUMMARY OF THE "BACKGROUND AND CONTEXT" THAT THE COMPANY PROVIDED ON ITS NATURAL GAS FORECAST METHODOLOGY.

A26. Mr. Snider discusses the history of recent avoided cost proceedings in North Carolina, highlighting a North Carolina Utility Commission ("NCUC") ruling that requires utilities to align forecasts used in their IRP and avoided cost proceedings.[52] He then focuses on

[50] ORS Sandonato Direct at 51.
[51] ORS Sandonato Direct at 51.
[52] Snider Rebuttal at 66.

the "overpayment risk" associated with PURPA contracts that were priced based on avoided costs[53] before making the baseless claim that the primary purpose of my testimony in this case was to influence the setting of avoided costs in another docket (and another state) that would result in the "solar development community [to] be poised for significant monetary gain."[54] Mr. Snider suggests in his testimony that the NCUC has generally approved of Duke's gas price forecasting methodologies, when in fact the opposite is true.[55]

Q27. HAS THE NCUC APPROVED DUKE'S NATURAL GAS FORECAST METHODOLOGY?

A27. No. The NCUC has repeatedly rejected Duke's natural gas forecasting methodology and its over-reliance on near-term market data. The Company's initial foray into using ten years of market data followed by a five-year transition to a fundamentals-based forecast occurred in the 2014 North Carolina avoided cost proceeding.[56] The NCUC rejected Duke's approach and directed the Company to revert to its methodology used in its 2014 IRP, which used only five years of market prices.[57] It also directed Duke to proposed changes in its natural gas forecast methodology in IRP proceedings, not avoided cost proceedings.[58]

Duke proposed such a change in its 2015 NC IRP Update report, and again in its full biennial 2016 NC IRP. The NCUC found the forecast methodology was "appropriate" for those matters but went on to note that "the Commission's acceptance of fuel forecasting methodologies in the present IRP docket shall not be precedent for or in any manner

[53] Snider Rebuttal at 67.
[54] Snider Rebuttal at 68.
[55] Snider Rebuttal at 66-68.
[56] N.C.U.C. Docket No. E-100, Sub 140
[57] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* Docket No. E-100 Sub 140 (N.C.U.C. Dec. 17, 2015) (2014 Sub 140 Order") at 27.
[58] 2014 Sub 140 Order at 28.

prejudice decisions to be made in the pending avoided cost proceeding in Docket No. E-100, Sub 148."[59] The NCUC also reversed its position on where changes in methodology should be proposed, determining "that specific issues related to fuel forecasting methodologies employed by the utilities, are best resolved in the context of the avoided cost proceeding."[60]

In the 2016 North Carolina avoided cost proceeding, Duke again proposed using ten years of market prices with a transition to fundamentals-based forecast in year 11.[61] The NCUC disagreed with this approach and found that "[i]t is appropriate to require DEC and DEP to recalculate their avoided energy rates using forward natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period."[62]

In the 2018 avoided cost proceeding, Duke again proposed to use the same natural gas forecast methodology.[63] And again, the Commission disagreed with this approach and declined to alter its previous (Sub 148) directive: "the Commission finds that it is appropriate to require DEC and DEP to continue to calculate their respective avoided energy costs using forward contract natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period."[64]

Despite two orders on this exact issue where the NCUC found that it was reasonable to require DEC and DEP to use *no more* than eight years of market prices before

[59] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans*, Docket No. E-100, Sub 147 (N.C.U.C. June 27, 2017) ("Sub 147 Order") at 39.
[60] *Id.*
[61] N.C.U.C. Docket No. E-100, Sub 148 (N.C.U.C. Oct. 11, 2017) ("2016 Sub 148") Order at 70.
[62] 2016 Sub 148 Order at 7.
[63] N.C.U.C. Docket No. E-100, Sub 158.
[64] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 158 (N.C.U.C. Apr. 15, 2020) ("2018 Sub 158 Order") at 59.

transitioning fully to a fundamentals-based forecast, Duke has for the third time ignored that directive and filed a forecast in this docket that utilized not eight, but fifteen years of market prices.[65]

Q28. DID DUKE EVER COMPLY WITH THE NCUC'S DIRECTIVES?

A28. Eventually. After years of failing to adhere to the NCUC's directives regarding its natural gas forecasts, Duke finally made a filing in the 2020 Sub 167 avoided cost docket conforming to the eight-year use of market prices.[66] However, in this docket and in the parallel IRP dockets in North Carolina, Duke has relied on a contrary methodology.

C. The Natural Gas Forecast Methodology is Critical to this IRP

Q29. WHY IS THE NATURAL GAS PRICE FORECAST IMPORTANT IN THE CONTEXT OF THE IRP?

A29. As Duke and other utilities transition away from coal generation, the pressing question is what assets should replace the capacity and energy served by the retiring coal units. DSM programs such as energy efficiency and demand response should be incorporated as robustly as possible, but the rest of the resource gap will need to be filled with some combination of replacement capacity, be it commercially-available natural gas generation, battery storage, or renewable energy generators.[67]

How this resource gap is filled is one of the fundamental questions to be answered in this proceeding. The scenarios evaluated calculate the costs of different resource combinations and their production costs, which are driven overwhelmingly by the price of

[65] Duke's methodology continues to utilize market prices in years 11 to 15 as it transitions to the fundamentals-based forecast. Lucas Direct at 66.

[66] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits NCUC Docket No. E-100, Sub 167 at 19.

[67] While other non-commercial resources such as small modular nuclear reactors, green hydrogen-powered gas turbines, or fossil plants with carbon capture and sequestration may play a role in the future, Duke recognizes that these resources are unlikely to be commercially available and economically feasible in the near term.

fuel. If one uses a natural gas forecast that is too low, the modeling will tend to favor the development of natural gas resources. This potential issue was identified by ORS's witnesses, who noted that "low gas price forecasts could result in indicating that natural gas-fired resources are comparatively less expensive than they otherwise would be relative to other resource alternatives."[68]

While the IRP does not provide automatic approval of individual resources (*i.e.*, Duke would still need to get a CPCN for any generation that was part of an approved IRP), this proceeding will send a strong signal about the most appropriate direction for Duke to pursue and will have implications for other issues before this Commission, like the timing and size of competitive procurement programs. Approving a plan that includes a massive natural gas build out, based in part on an unreasonably low natural gas price forecast, will de-prioritize or eliminate the near-term opportunity to cost effectively and reliably utilize zero-carbon renewables and energy storage as part of the "most reasonable and prudent" plan.

Q30. ARE THERE RISKS ASSOCIATED WITH A LARGE BUILD OUT OF NEW NATURAL GAS GENERATION?

A30. Yes, there are several risks, most of which will be borne by Duke's customers. The first is a reliability and cost risk arising from uncertainty about Duke's ability to secure firm natural gas transportation to its current and potentially expanded fleet of gas generating facilities. The Company has admitted that it needs more pipeline capacity than it currently has to meet its growing natural gas needs, and that without the recently-cancelled ACP it does not have a plan to access currently low-cost Marcellus or Utica basin gas.[69] If Duke

[68] ORS Sandonato Direct at 50.
[69] ORS Sandonato Direct at 51.

cannot deliver gas to its generating units, Duke's customers will be paying for generators that are not able to provide energy and capacity. Further, Duke's reliance on non-firm contracts for its peaker units may cause supply issues and pricing risk during periods of high demand, as was tragically demonstrated during the February 2021 electricity crisis in Texas.

Additionally, while Duke is able to earn a return on and return of capital expended for the construction of new natural gas units, Duke's customers bear the cost (and risk) associated with fuel expenses. In fact, over the lifetime of a high capacity factor NGCC unit, the fuel and operating expenses dwarf capital recovery costs. Figure 4 below is taken from a 2017 IRP for DTE Electric in Michigan, showing the relative portion of cost from various generating technologies broken down by capital, O&M, and fuel expenses on a $/MWh basis.[70] While DTE's natural gas assumptions may not match Duke's exactly, and the renewable cost values are out of date, it is instructive to note that roughly 80% of lifecycle costs of the NGCC come from fuel and O&M, expenses that are recovered from Duke's customers.

[70] Michigan Public Service Commission Case No. U-18419, K.J. Chreston Exhibit A-4 at 177.

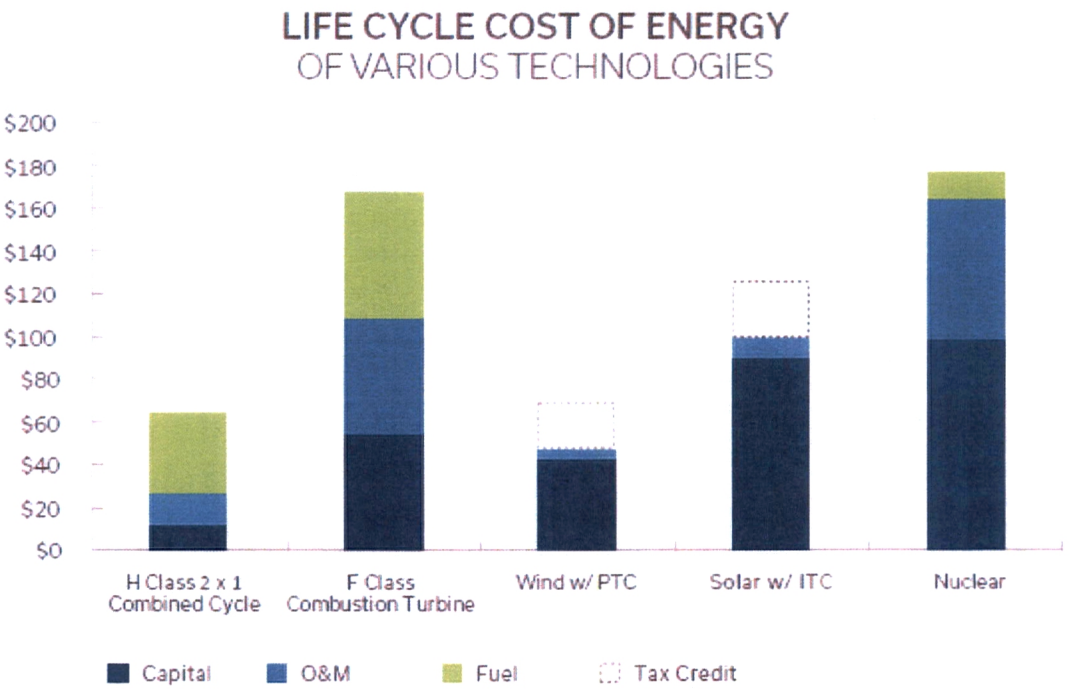

Figure 4 - DTE Life Cycle Cost of Energy

Duke's plans to build more natural gas units expose its customers to these costs and risks. By contrast, renewable energy has no variable fuel costs and its fixed O&M costs are a relatively small fraction of the total cost. The vast majority of solar costs are known up front and are not subject to fluctuations in fuel costs over the life of the project.

D. The "Risk of Overpayment" is Speculative and is Already Being Addressed

Q31. IS DUKE'S CLAIM THAT SOLAR QUALIFIED FACILITIES RECEIVE OVERPAYMENT VALID?

A31. No. Duke presents a calculation of possible overpayment that is highly speculative based on existing PURPA contracts (most of which were signed in the 2014-2017 time period) and the delta between the approved avoided costs and Duke's then-current forecast.[71] Of course, the accuracy of this calculation is wholly dependent on the accuracy of Duke's

[71] Direct Testimony of George V. Brown, Docket No. 2019-185-E (Aug. 14, 2019) at 16.

long-term forecast for natural gas prices, which is highly questionable. Duke simply cannot know what gas prices will be in 2030, making the calculation speculative at best.

In addition, avoided cost rates calculated in 2014-2017 reflected the higher capacity credits that solar was entitled to at the time. As more solar has come online, the capacity credit of incremental solar has fallen – but this does not call into question the capacity value of the solar that first went onto Duke's system. Duke's comparison of more current avoided cost rates, which account for the current level of solar deployment, to older avoided cost rates inappropriately discounts the capacity credit that those earlier facilities provided and ignores the very real benefit that they provided in reducing the summer peak. Similarly, the mere presence of additional zero marginal cost energy from now-existing QFs can affect the production modeling that determines the marginal cost in the future.

Duke's analysis also does not include any value for the benefit of zero-carbon resources. Solar QFs that displace coal or natural gas energy reduce both greenhouse gas and criteria pollutant emissions. While neither the Carolinas nor the federal government have yet implemented policies that reflect these costs in energy rates, as Duke acknowledges, it is increasingly likely that new regulations will be forthcoming and that Duke should begin to plan for their eventuality. In the meantime, these benefits do exist and should be accounted for when comparing the value of renewable generation. Duke's simplistic "overpayment" analysis completely ignores this element.

Additionally, Duke has identified several measures that have already been taken at the state and federal level to address any potential overpayment risk associated with QF contracts. As Mr. Snider recounts:

> NC HB 589 limits fixed price QF contracts over 1 MW in size to a five-year term to avoid overpayment risk while SC Act 62 limits prices for QF

> purchase contracts 10 years or longer to the Commission approved-10 year avoided cost price even if the contract is longer than 10 years... Finally, also in 2019, FERC Order 872 amended the federal PURPA implementation rules in a manner that now affords states the ability, at their discretion, to set PURPA rates that do not include a long-term fixed energy component siting concerns of overpayment risk for consumers.[72]

These developments mitigate many of the circumstances Duke identified, even if one accepts the faulty premise of its calculation. The number of QFs that are signing these contracts and not participating in other program such as the Competitive Procurement of Renewable Energy ("CPRE") had already slowed substantially by 2018. Further, Duke's own projections show relatively little new PURPA development occurring in the next five years, with most solar commissioned during that time period having shifted to CPRE or having already signed PPAs.[73]

E. Response to Duke's Rebuttal Testimony Regarding Natural Gas Price Forecasts

Q32. MR. SNIDER REMARKS THAT MARKET PRICES ARE SUPERIOR TO FUNDAMENTALS-BASED FORECASTS BECAUSE "THERE IS ONLY A SINGLE FORWARD MARKET PRICE AT ANY POINT IN TIME."[74] WHAT IS YOUR RESPONSE TO THIS?

A32. Mr. Snider's comment is accurate but irrelevant to the issue at hand. He was contrasting the fact that there are multiple firms that produce fundamentals-based forecasts, meaning that at any point in time there may be more than one view on what the future would bring. By contrast, the "forward market price" Mr. Snider is presumably referring to is that of the NYMEX NG future, which settles on a single price daily.

Mr. Snider's support for a single price in the NYMEX futures market contrasts confusingly with his testimony in this and past proceedings pointing out the difference

[72] Snider Rebuttal at 77-78.
[73] Kalemba Rebuttal Exhibit 1
[74] Snider Rebuttal at 70.

between the futures market and the OTC swaps on which Duke's forecast is based.[75] Intentionally or not, this insight accurately demonstrates the intimate relationship between the NYMEX futures prices and OTC swap prices. After all, the OTC swap price that Duke obtained for this case was practically identical in every month over ten years to the corresponding NYMEX future price of the same day.[76] This makes intuitive sense as there are few other sources for brokers to obtain their baseline pricing information for the swaps than from the NYMEX future market, despite its lack of liquidity in the long-term.

Regardless, despite Mr. Snider's latest testimony on this point, having multiple fundamentals forecasts at one time is a strength, not a flaw. In fact, my methodology recommends that the average of different forecasts be taken as it is often the case that averaging several forecasts produces more accurate results than any single forecast. The "single price" that Mr. Snider lauds changes not once or twice a year, but hundreds of times per year. Further, these changes are not inconsequential. Figure 5 below is taken from my direct testimony and shows the variability of the "single price" over a short period of time, showing sizable variation over both the short-term and long-term prices.[77]

[75] See e.g. Snider Rebuttal at 73; Direct Testimony of Glen A. Snider, Docket No. 2019-185-E at 26; 2016 Sub 148 Order at 71-72 (quoting Mr. Snider testimony on the issue).
[76] Lucas Direct at 70.
[77] Lucas Direct at 81.